3

Chapter 3 – Need for Baseload Capacity in Southeastern Wisconsin

WEPCO proposes to build three additional units or 1,830 MW of coal-fired generation over the next eight years. The need for all or a portion of this capacity, particularly as baseload generation, is explored in this chapter.

In determining the need for a proposed power plant, peak demand, energy use, and implications on reliability are examined. Forecasts of future peak demand and energy use typically include a multi-year projection of the annual maximum demand for power in kilowatts and energy use, in kilowatt hours.

Planning at least five years into the future is required for large generating units because of the construction lead-time necessary. The further into the future demand and energy use are predicted, the more uncertain the data becomes. To avoid paying for plants before they are required, there is a need to accurately balance future supply and demand. Appropriate planning for additional generation to meet future needs requires accurate forecasting of the variables and is best accomplished by making incremental changes in the generation supply instead of large changes all at once.

In addition to balancing supply and demand, an analysis of the generating system reliability is required. Reliability is based on the demand for electricity and the operating and reliability characteristics for each individual plant in the system.

Reliable service typically is defined by a lack of power interruptions. WEPCO must maintain sufficient peaking capacity and purchase power arrangements to cover unscheduled or planned outages from its generation supply during peak demand. The Mid-America Interconnected Network (MAIN) guidelines typically require about 15 percent target reserves. The PSC has traditionally required Eastern Wisconsin utilities to maintain a higher 18 percent planning reserve margin due to concerns with issues such as transmission limitations.

The optimal choice for new generation is determined by examining all of the possible generation addition plans that would meet the projected peak demand and energy use with an adequate level of reliability. The need to have an adequate mix of fuel sources (coal, nuclear, gas, and renewables) is discussed in this chapter. Alternative plans that could potentially substitute for the ERGS proposal are discussed in Chapter 4 and compared on the basis of cost, reliability, and environmental impacts.

Recent History of Reliability in WEPCO's (EWU's) Service Territory

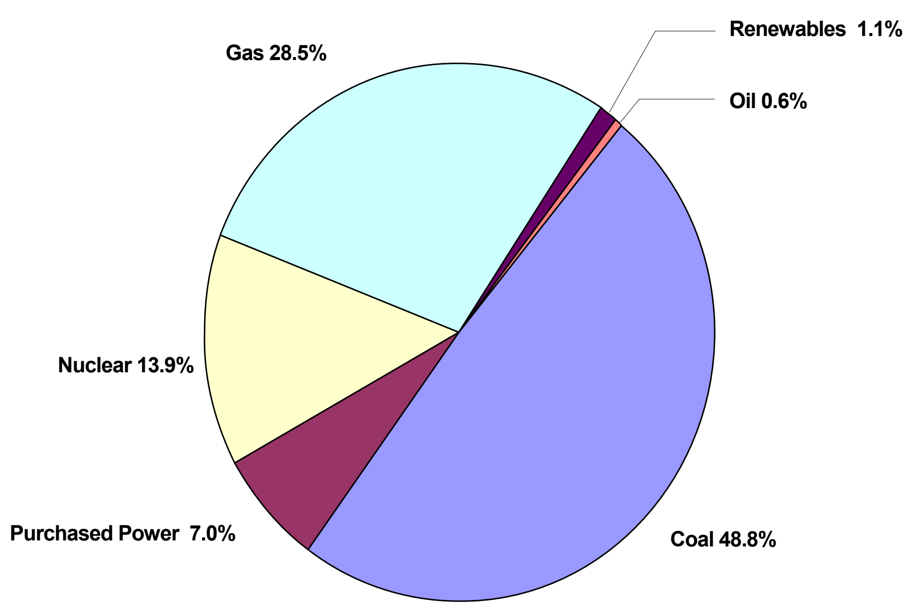
WEPCO's peak load for 2002 was 5,479 MW [31] with an estimated peak of 5,624 MW for 2003, as reported in its 2002 Wisconsin Strategic Energy Assessment (SEA) filing. Available WEPCO-owned capacity at peak, for 2003, is 5,053 MW. In addition, WEPCO has 948 MW contracted from merchant power plants and expects 411 MW of purchases without reserves. Adjusting for its Upper Michigan load of 98 MW results in a total supply of 6,430 MW in 2003, as reported in the SEA. The Mid-American Interconnection Network (MAIN) audit shows a 20.56 percent reserve margin in 2003 for WEPCO.

For planning future needs, it is desirable for WEPCO to maintain the 18 percent planning reserve margin recommended by the PSC. The 18 percent reserve is greater than some North American Electric Reliability Council (NERC) sub-region guidelines because it is meant to take into account transmission constraints within the Wisconsin Upper Michigan System (WUMS).

Adequacy of existing supply for peak demand

Although its reserve margin for 2003 is 20.56 percent, WEPCO is becoming increasingly dependent on power purchases to meet its needs. Figure 3-1 indicates that seven percent of its capacity will be power purchases to meet the anticipated peak demand. This does not include merchant plants under contract to WEPCO which are included as part of the gas section.

Figure 3-1 WEPCO's summer capacity available for 2003 peak demand

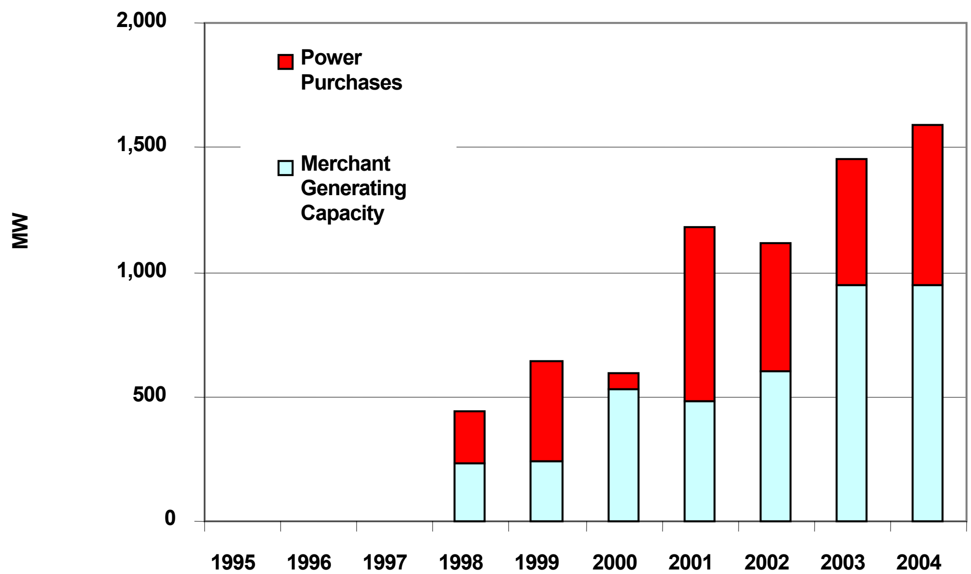


[31] Peak load not weather normalized and for Wisconsin only load of WEPCO.

No guidelines are specified for utilities on how to meet the PSC reserve margin; therefore, utilities have opted to pursue numerous options. To obtain the required 18 percent planning reserve margin, WEPCO has increased its reliance on interruptible load, load control, and increased purchases with reserves to reduce its peak load. On the supply side, WEPCO has increased its reliance on merchant plant capacity purchases and purchases without reserves, some of which are located outside of Wisconsin.[32]

Figure 3-2 shows the amount of WEPCO's capacity comprised of power purchases and merchant plant generating capacity. The additional three percent added to the reserve margin by the PSC was intended to allow for transmission constraints and other reliability issues. Three percent of WEPCO demand is approximately 150 MW, but the amount of purchase power WEPCO relies on is growing to levels well beyond this. Because these purchases have in turn increased the strain on a transmission system that is already viewed as overloaded, it is unlikely that this trend can continue. This implies that there may be a need for more baseload capacity in Wisconsin and more transfer capability.

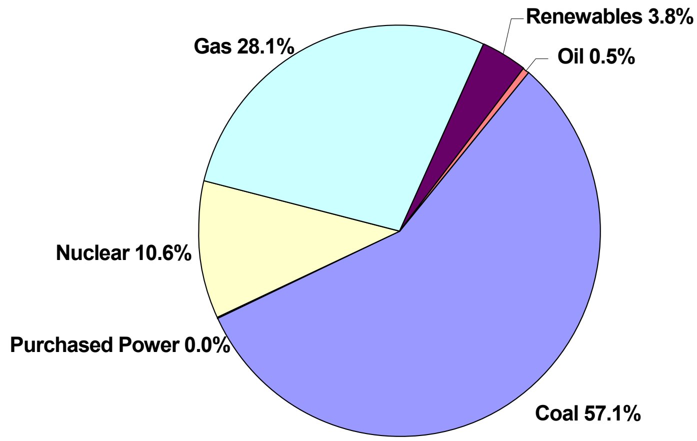
Figure 3-2 WEPCO's power purchases and merchant plant capacity



A mixture of baseload, intermediate load, and peaking load generation is required for an adequate generation mix as well as a mixture of fuel types. The baseload units in WEPCO's fleet consist of: Pleasant Prairie 1 and 2; Oak Creek 5, 6, 7, and 8; Point Beach 1 and 2; and WEPCO's 25 percent share of the Edgewater generating unit. Figure 3-3 presents the summer capacity in 2011 if all Port Washington and ERGS units are built.

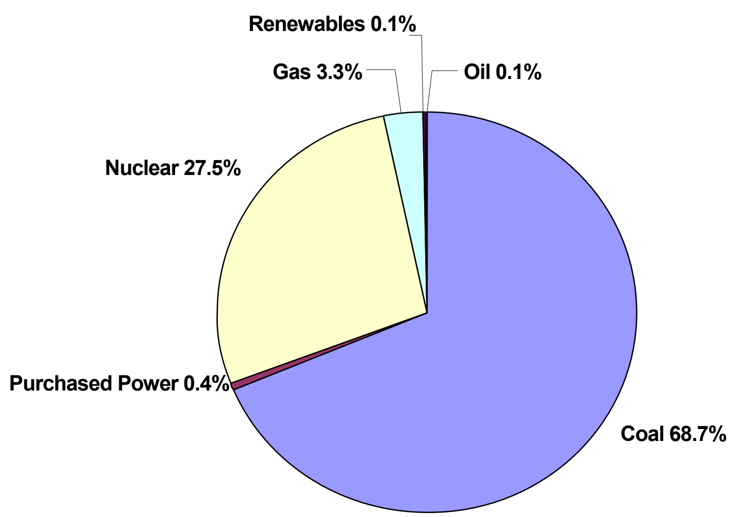
[32] The distinction between purchases with reserves and purchases without reserves pertains to the power seller's responsibility for planning reserves. A purchase with reserves means the seller is required to have sufficient capacity to back up the sale as if the seller were delivering the power for use by its own native load customers.

Figure 3-3 WEPCO's summer capacity available for 2011 peak demand (if ERGS and PWGS are constructed as planned)



Compared to the summer capacity chart for 2003, the percent of gas generation would remain the same, the percent of coal generation would increase, and the percent of nuclear would decrease. Figure 3-3 assumes that WEPCO would sign no purchased power contracts, which in all likelihood is false. However, at this point it is not possible to forecast the number of contracts or the capacity they would provide. If the purchases are gas-based, the coal percentage would be lower.

Figure 3-4 WEPCO's energy production by fuel for 2001 in MWh



Adequacy of existing supply for energy use

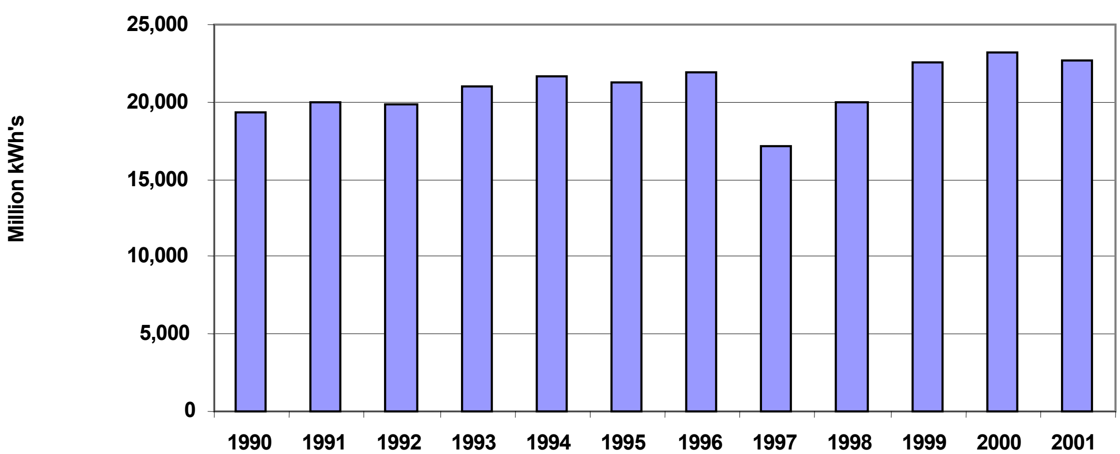
Coal-fired generation accounts for the majority of WEPCO's energy produced, as shown in Figure 3-4.[33] Nuclear power, which has represented greater than 25 percent of WEPCO's energy needs, will probably have a declining role if energy use continues to rise. Natural gas generation has increased to over 3 percent. The amount of future natural gas capacity will be highly dependent on the price of future fuel supplies. To meet the increase in energy use, there is a need for additional capacity with low fuel costs and high capacity factors to meet the changing energy needs. The different generating options and the changes that could result in the energy used to generate power are evaluated in Chapter 4.

Existing Generation Supply

Baseload generation of energy

The existing baseload plants are aging and at the same time have come under greater pressure to increase their output. The last baseload power plant constructed by WEPCO was Pleasant Prairie, Units 1 and 2 in 1985. While the growth in peak demand of the last decade was met by the installation of combustion turbines, the growth in energy use has been met in additional ways. The energy produced from WEPCO baseload generating units during the last decade increased by 15 percent as shown in Figure 3-5.

Figure 3-5 kWh production for WEPCO generating units built after 1960

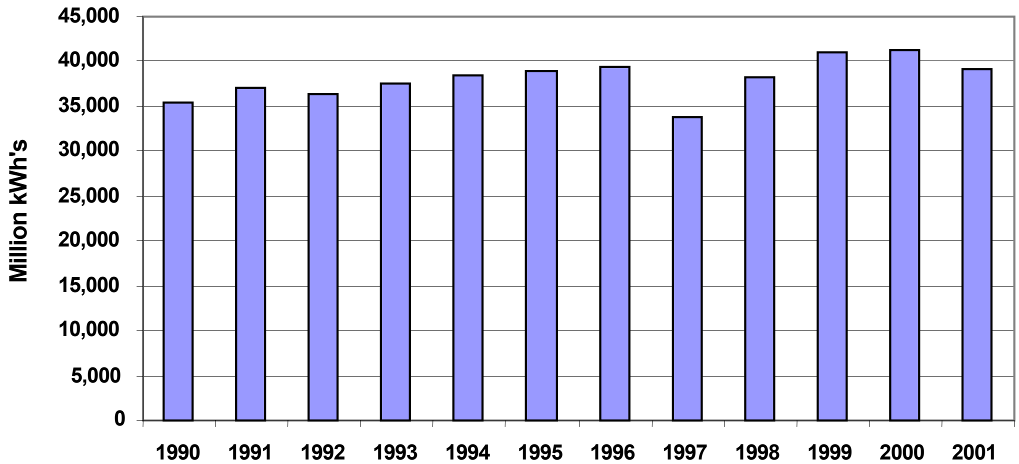


This increase is comparable to the trend seen in the rest of Wisconsin utilities where an increase of 9 percent has occurred (see Figure 3-6). The reduction in 1997 was due to the Point Beach and Kewaunee nuclear units being out of service for an extended period. The existing baseload plants have encountered higher capacity factors as production costs remained less than those for the newly installed combustion turbines.

[33] WEPCO purchases additional renewables amounting to between 2 and 5 percent of its sales that is not accounted for in its production.

Further production increases from the existing baseload generating units are not anticipated, and any shortfall in production would need to come from other sources.

Figure 3-6 kWh production for Wisconsin generating units built after 1960



Increased baseload energy use means the available time to work on multiple generating units during spring and fall maintenance seasons is further constrained. As a result, the outage "season" for Wisconsin is starting earlier and continuing later. As seen this past January, the need for maintenance at baseload facilities and unexpected forced outages during colder weather can force combustion turbine units into service during periods of high gas demand. As a planning issue, the implications of needing a large amount of gas generation to be available during the winter have been overlooked and requires further investigation, especially with the predicted increase in gas generation.

An increase in energy use has also been seen at the end of the outage "season" in May or the beginning of the fall season in September. Warm weather results in increased air conditioning load and a need to run gas turbines while baseload capacity is out of service.

In addition, the effect of peak demand reduction programs, such as direct load control and interruptibles, is contributing to reducing the time available for maintenance of existing baseload units. Summer peak demand reduction through active and passive kW programs, lessens the difference in demand between the spring and fall "shoulder" months and the summer peak month. In essence, this leaves less "room" to take multiple units out of service for routine maintenance.

As a market indicator, utilities have seen the forward-looking prices for purchased power in Wisconsin increase. This indicates that the costs for replacement generation are no longer based on the next available coal-fired baseload plants but on the next available gas generation plant.

Previous generation supply plans

WEPCO's 1976 long range expansion plan, developed to match the projected peak demand and projected energy demands, indicated 2,000 MW of coal-fired generation, 1800 MW of nuclear generation, and 213 MW of gas generation (see Table 3-1) would be required.

Table 3-1 WEPCO's proposed expansion plan in 1976

Year	Generating Units	Estimated MW	Actual MW
1979	Germantown combustion turbines	213	245
1980	Pleasant Prairie I	580	600
1982	Pleasant Prairie II	580	600
1984	A share of Koshkonong I coal-fired plant	440	
1985	A share of Koshkonong II coal-fired plant	400	
1987	A share of the Haven I nuclear plant	900	
1989	A share of the Haven II nuclear plant	900	

The Koshkonong and Haven power plants were never built as the energy demand discussed earlier never materialized until the late 1990s. Growth in energy and peak demand did, however, continue to increase. WEPCO met its generation needs accordingly by installing less costly combustion turbines at Paris and Concord as shown in Table 3-2.

Table 3-2 Generating units installed by or under contract to WEPCO since 1985

Year	Generating Units	Estimated MW	Actual MW
1993-94	Concord combustion turbines	344	382
1995	Paris combustion turbines	344	382
1997	Whitewater combined-cycle (purchase)	235	247
2000	Germantown 5 combustion turbine	95	95
2000	Neenah combustion turbines (purchase)	300	350
2004	Zion combustion turbines (Illinois purchase)	450	
2005	Port Washington combined-cycle	545	
2008	Port Washington combined-cycle	545	

In addition to the generating units it built, WEPCO arranged a 235 MW power purchase from the Whitewater combined-cycle generating unit and it expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois by 2003. Advance Plan 7, filed in 1994, identified a future need for 500 MW of baseload facilities in 2011 and 2013. While use of 10- to 20-year Advance Plans has now been superceded by a two-year focused Strategic Energy Assessment, planning exercises over the past decade have identified a need for new baseload generation after 2007.

Other plants built or under construction within Wisconsin or that have ties to Wisconsin load are listed in Table 3-3.

Current generation supply plans

After the Advance Plan statute was repealed, the Strategic Energy Assessment (SEA) was created as its replacement. The SEA, issued every two years, has only a two-year outlook. Thus, large generation projects that require a longer lead time may not be disclosed or discussed.

Table 3-3 Other generating units greater than 50 MW installed or under construction in Wisconsin since 1998, or tied to Wisconsin load[34]

State	Year	Generating Units	Estimated MW	Utility Served
Wisconsin	1999	De Pere CT	175	WPSC
Wisconsin		Marinette CT		MGE
Wisconsin	2001	Rock Gen Christiana CT	450	WP&L
Wisconsin	2001	Elk Mound CT	96	DPC
Illinois	2001	Cordova CC	500	
Illinois	2002	Kendall Energy Center CC	1,000	
Wisconsin	2003	Pulliam CT	83	WPSC
Wisconsin	2004	Kaukauna CT	52	WPPI
Wisconsin	2004	Riverside CC	600	WP&L

Due to deregulation of wholesale power markets at both the state and federal levels, non-utility generation has been the supply area in which significant power plant construction has taken place in recent years. As late as 1996, there were no merchant power plants in the state. Beginning in 1997 with the operation of the LS Power (now Cogentrix) 235 MW cogeneration facility at the University of Wisconsin-Whitewater, there has been an expanded use of wholesale merchant power plants. In 1999, the 175 MW Polsky Energy Corporation combustion turbine unit in De Pere began commercial operation (the plant was subsequently purchased by WPSC). During the summer of 2000, SEI Wisconsin, the predecessor of Mirant, placed a 300 MW natural gas facility in Neenah into commercial operation (the plant subsequently was purchased by Alliant Generation). During 2001, the 450 MW RockGen combustion turbine project located in the town of Christiana in Dane County began full operation. All of these facilities are under contract to various state utilities. The sale of some of the merchant power plants to Wisconsin utilities reduces the amount of generation that merchant plants were predicted to supply toward the state's generation needs.

By the end of 2004, nearly 2,050 MW of electric generating supply being used by electricity providers for Wisconsin customers may come from merchant plants under contract to the states' utilities. Some of this power will come from merchant facilities located outside the state; such capacity plays an important part in maintaining electric reliability in the state. For instance, by 2003, WEPCO expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois.

Power plants approved by the PSC but not expected to start construction in the near future include: a 1,050 MW combined-cycle unit in Kenosha County proposed by Badger Generating, LLC, a unit of Pacific Gas and Electric; a 900 MW facility in the Plover area of Portage County proposed by Mirant Corporation; and a 170 MW combustion turbine facility in Superior planned by Rainy River.

[34] The table does not include the Badger Gen, Rainy River, Fox Energy, or Mirant power plants which have PSC approval but have not been constructed. These projects have been placed on hold because they have been unable to sign contracts with Wisconsin electricity providers and because of the widespread financial difficulties in the IPP markets.

A shift toward a deregulated electricity market in the 1990s was supposed to allow merchant power plants the opportunity to compete with the electric utilities for providing wholesale power at competitive rates. Competitive alternatives for generation, however, have not fully materialized for several reasons:

- The financial standing of many IPPs is questionable. Financing is difficult without long-term power purchase agreements.
- Utilities have been reluctant to sign long-term contracts with IPP's because of their uncertain financial situation.
- A lack of available firm transmission services into Wisconsin hinders agreements with IPP's outside of Wisconsin.
- IPP projects are gas-fired, not coal, for the most part and natural gas prices have been higher than predicted.

Capacity needs in surrounding states

States surrounding Wisconsin have addressed capacity needs in different ways. Illinois, which was in the forefront of the deregulation movement a few years ago, has had over 10,000 MW of combustion turbines installed and 5,000 MW of combined-cycle generating units constructed since 1998. Much of this generation is located south and west of Chicago. Transmission constraints between northern Illinois and Wisconsin however, limit the options available to Wisconsin utilities beyond the merchant power plants listed in Table 3-3.

Iowa has not built a baseload power plant since the late 1970s and energy demands are expected to exceed supplies by 2003. Deregulation plans have been delayed. In May 2003, the Iowa Utility Board approved a 750 MW coal plant proposed by Mid American Energy Company. That plant would be located in Council Bluffs, Iowa.

Minnesota has not built a baseload power plant since the late 1980s and anticipates the need for two or three large coal or nuclear plants.

Recently approved transmission capacity

Existing transmission

The existing high voltage and extra high voltage (EHV 230 and 345 kV) systems in southeast Wisconsin have been just adequate to meet current generation and load serving requirements. Since the start of 2003, contracts for additional firm import power (beyond existing contracts) from northern Illinois have been mostly denied by the Midwest Independent System Operator (MISO). Recently, Alliant was granted a 100 MW contract for the summer of 2003.

The interstate transmission lines to the west and south have been in transfer-limiting condition for the past two years. When transmission lines can be overloaded with a single outage, the system operator issues a Transmission Loading Relief (TLR) order to mitigate the problem and reduce the chances of cascading power failures. Power flow issues are quite complex and can originate from several causes, including local generation dispatch, line maintenance, generation maintenance, interstate power transfers, or inadvertent loop flow. Selected TLR incidents from the year 2001 are listed in Table 3-4 below.

MISO tracks the number of hours that its flowgates are in a TLR. MISO's footprint covers Wisconsin, Michigan, Minnesota, Dakota's, Nebraska, Iowa, Missouri, Kansas, Indiana, Ohio, and Kentucky. During 2001, only five months had "flowgate hours in TLR" (FG-HR) that exceeded 500 hours when considering the sum for each month. The largest monthly total was 800 FG-HR. This indicator of system transfer capability has steadily declined since 2001. From June 2002 to December 2002, no month has had less than 700 FG-HR. September 2002 had almost 1,400 FG-HR.

The levels of mitigation that involve curtailment of power transactions start at level 3. The definitions for each level are:

Level 3a: Curtail transactions using Non-firm Point-to-Point transmission service to allow transaction using higher priority Point-to-Point transmission service.

Level 3b: Curtail transactions using Non-firm Point-to-Point transmission service to mitigate operating security limit violations.

Level 4: Reconfigure transmission system to allow transactions using Firm Point-to-Point transmission service to continue.

Level 5a: Curtail transaction (pro rata) using Firm Point-to-Point transmission service to allow new transactions using Firm Point-to-Point transmission service to begin (pro rata).

Level 5b: Curtail transactions using Firm Point-to-Point transmission service to mitigate operating security limit violations.

ATC has plans to improve the 138 kV problems noted in the above table. Work is now in progress in the Janesville area and in the Mukwonago area. ATC's 10-Year Assessment – Full Report – August 2002 notes other system performance limitations in the southeast portion of Wisconsin, which it designates as Zone 5. The other limitations include low voltages, overloads, and the accommodation of new generation.

Table 3-4 Selected 2001 transmission loading relief (TLR) incidents

Limiting element*	Contingent element	# days at level 3, 4, or 5
Albers - Paris 138 kV	Wempleton - Paddock 345 kV	21
Blackhawk Colley Road 138 kV	Paddock -Rock River 138 kV	12
Eau Claire – Arpin 345 kV		10
Mukwonago – Whitewater 138 kV	South Fond du Lac - Columbia 345 kV	2
Paddock - Blackhawk 138 kV	Paddock - Rock River 138 kV	4
Paddock - 345/138 kV Transformer	Paddock - Rockdale 345 kV	22
Pleasant Prairie - Racine 345 kV	Wempleton - Paddock 345 kV	1
Russell –Rockdale 138 kV	Paddock - Rockdale 345 kV	8
Wempleton - Paddock 345 kV		7

*Limiting element identifies the transmission segment that will become overloaded if the contingent element trips out of service unexpectedly.

Figure 3-7 shows the MISO curtailment flowgate-hours by TLR level for the months from January 2001 to December 2002.

Proposed transmission additions in southeastern Wisconsin

There are several transmission projects planned for Zone 5 (southeastern Wisconsin) that would address existing and near term reliability issues. Some of the larger projects planned by ATC are listed in Table 3-5 below. These items were selected from ATC's recent 10-Year Assessment Update, February 2003. This table does not include the additions that would be associated with the ERGS.

Figure 3-7 MISO curtailment flowgate-hours

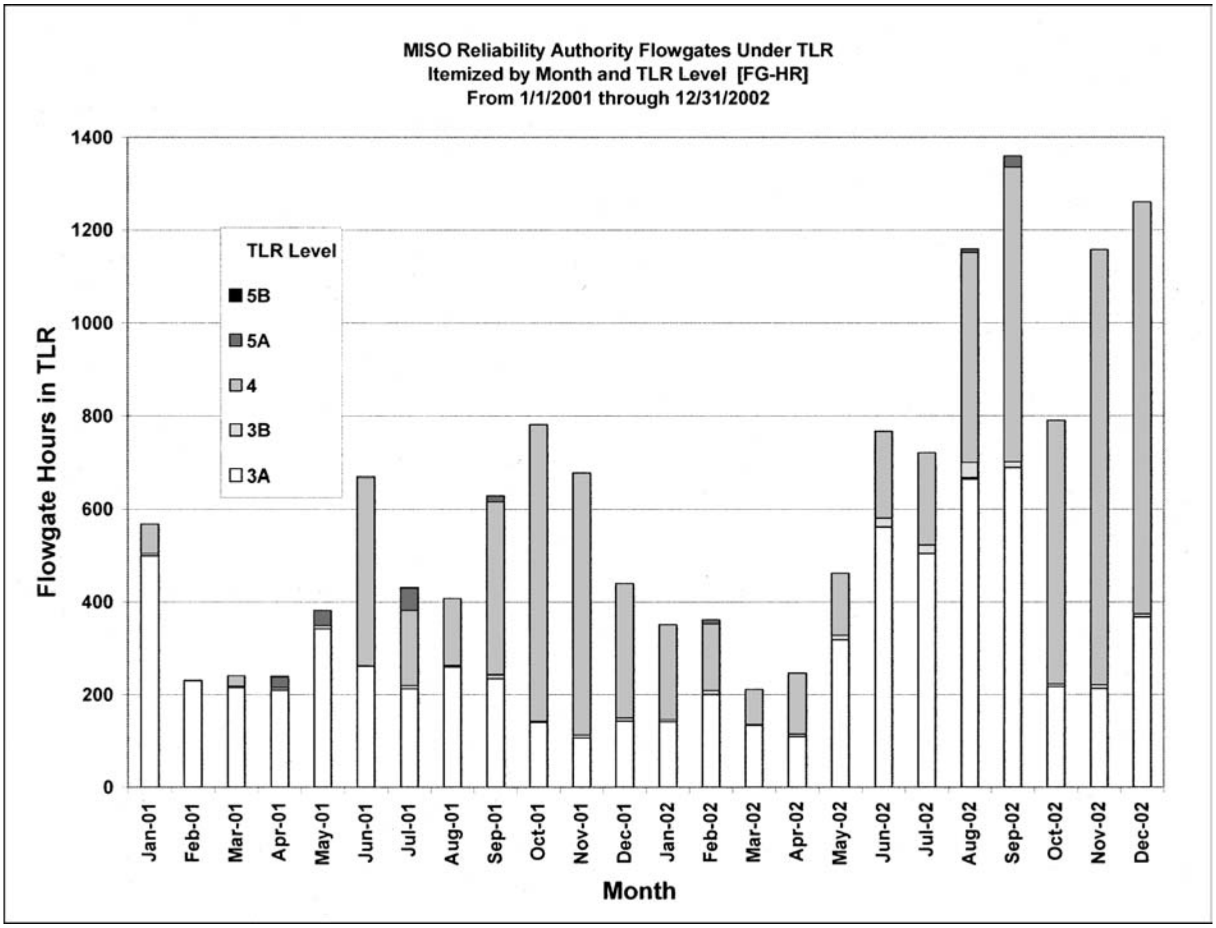


Table 3-5 Selected ATC Zone 5 improvements

Planned Additions	Projected In-Service Date	Need Category
Install 2 - 26 MVAR capacitor banks at Sussex 138 kV	2002	Reliability
Reconductor Mukwonago - Whitewater 138 kV line	2003	Condition, reliability, service limitation, new generation
Uprate Pleasant Prairie - Arcadian 345 kV line	2004	Service limitation, reliability
Rebuild Port Washington - Range Line double circuit 138 kV line	2004	New generation
Construct a new Lannon Junction sub at intersection of Granville-Arcadian 345 kV, Forest Junction - Arcadian 345 kV, Sussex -	2005	Reliability and Germantown generation stability

Planned Additions	Projected In-Service Date	Need Category
Tamarack 138 kV and Sussex -Germantown 138 kV lines; install 345/138 kV, 500 MVA transformer		
Construct a Waukesha - Duplainville - Sussex 138 kV line	2005	T-D interconnection
Rebuild Port Washington - Saukville double circuit 138 kV line	2005	New generation at Port Wash.
Rebuild Port Washington- Saukville single circuit 138 kV line	2005	New generation at Port Washington
Install 138 kV capacitor banks at Summit, Tichigan, Bluemound, and Moorland	2007	Reliability

Planned capacity retirements and nuclear relicensing

In its CPCN application, WEPCO indicated that no existing baseload capacity would be retired in the near future. However, retirement of OCPP units 5 and 6 has been made a condition of the WEPCO-US EPA Consent Decree released in May 2003. Commission staff recommended considering retirement of a generating unit at 60 years and this assumption was incorporated into the EGEAS modeling. Any forced retirements would most likely increase the need for additional generating capacity. Chapter 4 EGEAS base runs assume that OCPP units 5 and 6 are retired in 2012.

No retirement of any nuclear units was factored into staff's analyses. All expansion plans assumed successful relicensing for Units 1 and 2 at the Point Beach Nuclear Power Plant. Any forced retirements would most likely increase the need for additional generating capacity.

Projected Growth, Electric Demand, and Energy

This section discusses past and future projections of growth in energy use and peak demand. A review of previous forecasts for energy requirements indicates the levels of growth predicted have been reached for both energy use and peak demand but usually later than originally predicted. The projections for future growth appear reasonable and are based on a growing economy. If the recent economic slowdown were to continue, the need for additional generation may not be forthcoming or simply delayed. Past history indicates predicting growth accurately beyond a period of five years is very difficult.

Historic growth in energy use

Energy use has continued to grow over the last 30 years, although at a rate less than originally anticipated in the mid-1970's. The growth has been steady and linear. The Environmental Impact Report developed for Pleasant Prairie Units 1 and 2 in 1976 provided projected annual energy requirements up to 1989. These values are shown in Figure 3-9.

The total sales by WEPCO were predicted to reach 30,000 MWh in 1987. Growth in energy use has been steady, yet total sales did not reach the 30,000 MWh level until 1999.[35] Growth in 2001 and 2002 occurred in the residential and commercial sectors while the industrial sales decreased, resulting in no load growth in

[35] FERC Form 1 Page 301 Line 14

2001 and 2002. Energy use or total sales by WEPCO have continued to increase approximately 2.7 percent per year since 1992 as shown in Figure 3-10.

Figure 3-9 WEPCO projected energy demand since 1976

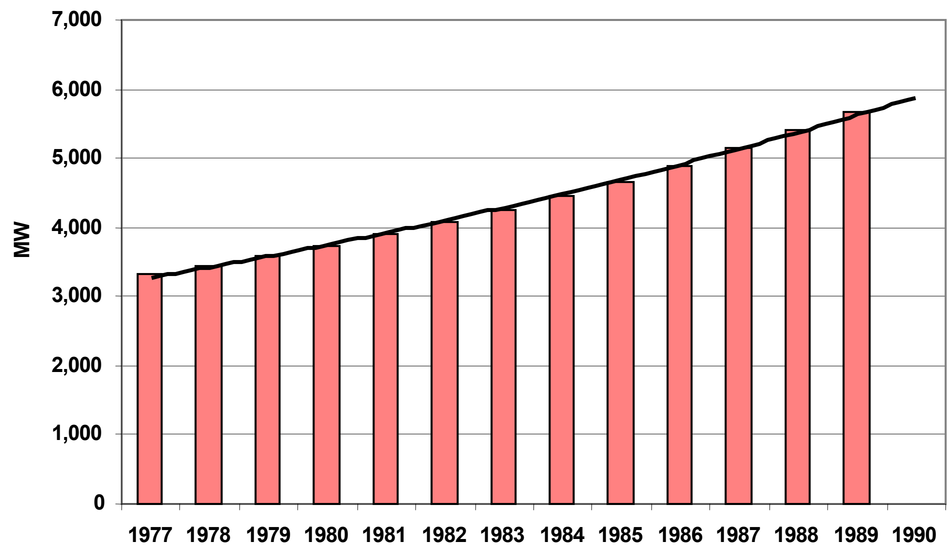
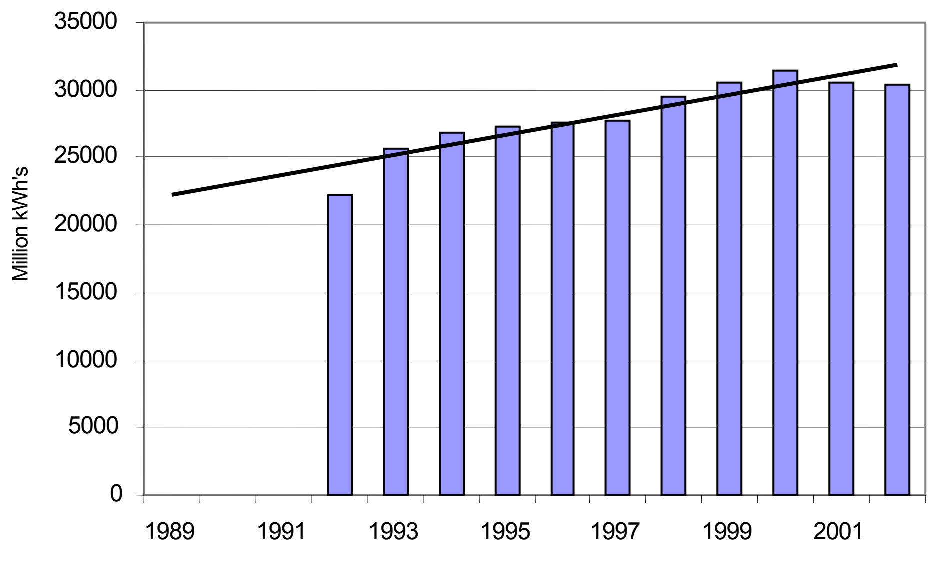


Figure 3-10 WEPCO total sales



WEPCO's annual growth in energy use has been slightly greater than the state's energy use measured in total sales. Figure 3-11 provides an indication that over the past 30 years, growth in total sales for Wisconsin electric utilities has averaged about two percent per year.

Figure 3-11 Sales from Wisconsin electric utility power generation: 1970-2001

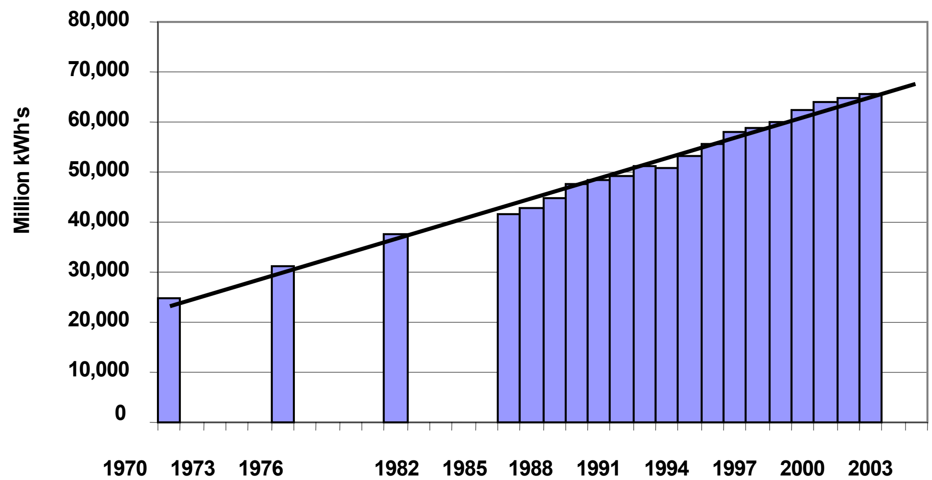
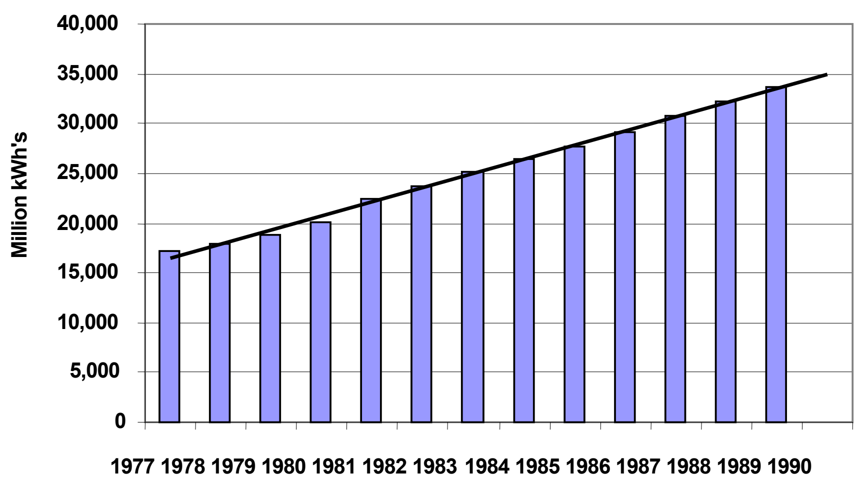


Figure 3-12 WEPCO projected demand in 1976



Historic growth in peak demand

The 1976 projected peak demand is shown in Figure 3-12.

The peak demand predicted was estimated to reach 5,500 MW by 1989. This peak was not reached until 2000[36] but the peak demand has steadily increased. Since 1997, the normalized native system, excluding peak load of mines, has continued to increase approximately 2.5 percent per year as shown in Figure 3-13.

Figure 3-13 Normalized native system excluding mines peak

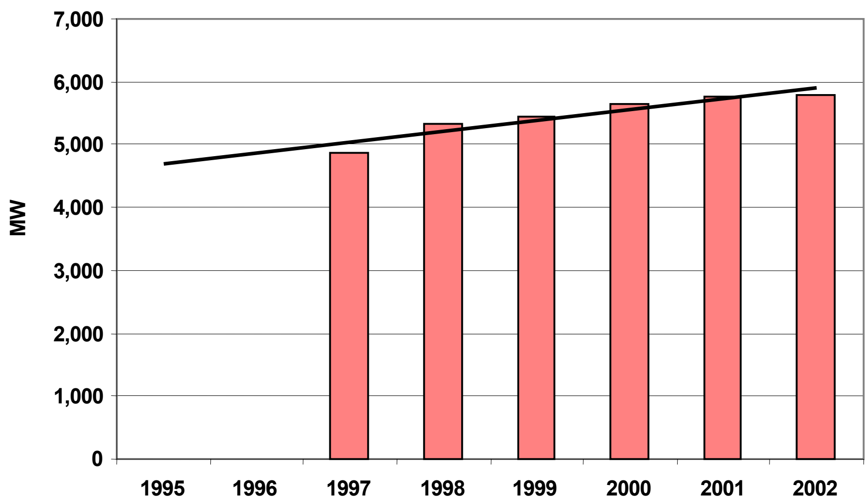


Table 3-6 Summary of peak and energy forecasts: WEPCO and MAIN Region

Year	Peak Demand (MW)		Energy Use (GWh)	
	WEPCO	EIA MAIN Growth Rates	WEPCO	EIA MAIN Growth Rates
2002	5,778	5,778	30,877	30,877
2005	6,276	6,223	33,379	33,254
2010	7,258	6,971	37,920	37,250
2015	8,166	7,665	42,024	40,958
2020	9,175	8,321	46,345	44,464
2025	10,295	8,925	48,974	47,689
2030	11,280	9,515	52,735	50,845
Growth Per Year				
2002-2005	2.8%	2.5%	2.6%	2.5%
2005-2010	3.0%	2.3%	2.6%	2.3%
2010-2015	2.4%	1.9%	2.1%	1.9%
2015-2020	2.4%	1.7%	2.0%	1.7%
2020-2025	2.3%	1.4%	1.1%	1.4%
2025-2030	1.8%	1.3%	1.5%	1.3%

36 Response to DR-067

Projected growth in energy use and peak demand

Table 3-6 shows both the growth in electric demand and energy use forecasted by WEPCO through 2030 and the lower growth rates used by the Energy Information Administration (EIA) in its estimates of energy growth rates for the Mid-America Interconnected Network (MAIN) through 2020 as applied to WEPCO.

In this docket Commission staff required WEPCO to provide an updated electric demand and energy forecast from the forecast it used for the Port Washington CPCN case (docket 05-CE-117). The company generally lowered its growth estimates for peak and energy relative to the forecast provided for the Port Washington case. However, WEPCO's forecasted growth rates from 2002 through 2011 in this case are very close to those it used for the Port Washington case. Commission staff made a more detailed analysis of WEPCO's updated forecast, analyzing the residential, commercial and industrial sectors. Staff's analysis indicates that WEPCO's updated electric demand and energy forecast is reasonable although it may have a slight upward bias.

Just as in the Port Washington case, Commission staff applied the forecasted growth rates to WEPCO estimated by the EIA for the MAIN region for 2002 to 2020. Commission staff used also the EIA MAIN forecasted increase for 2019 to 2020 for the period 2020 through 2030. The EIA forecast is for energy use only. Commission staff assumed that the growth rate in peak demand would be the same as the growth rate in energy during this period. The difference between the two forecasts is an increase in peak demand of 500 MW in the WEPCO forecast by the year 2015. Under the EIA MAIN forecast, WEPCO would not need the capacity represented by the third coal plant until much later.

Figure 3-14 WEPCO peak load compared to generation supply with and without the Port Washington and ERGS units, and assuming no Oak Creek unit reqirements

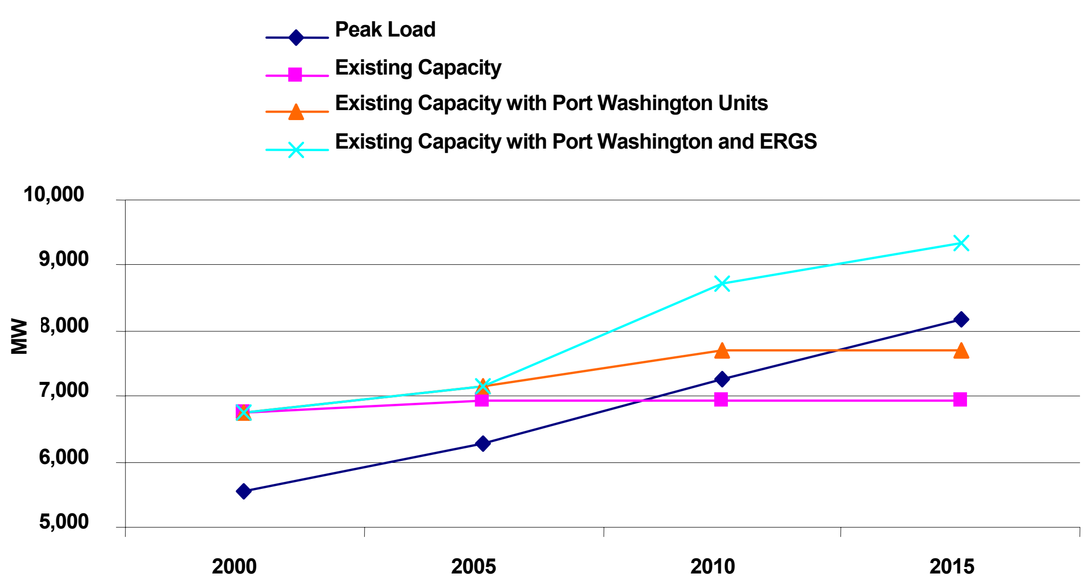
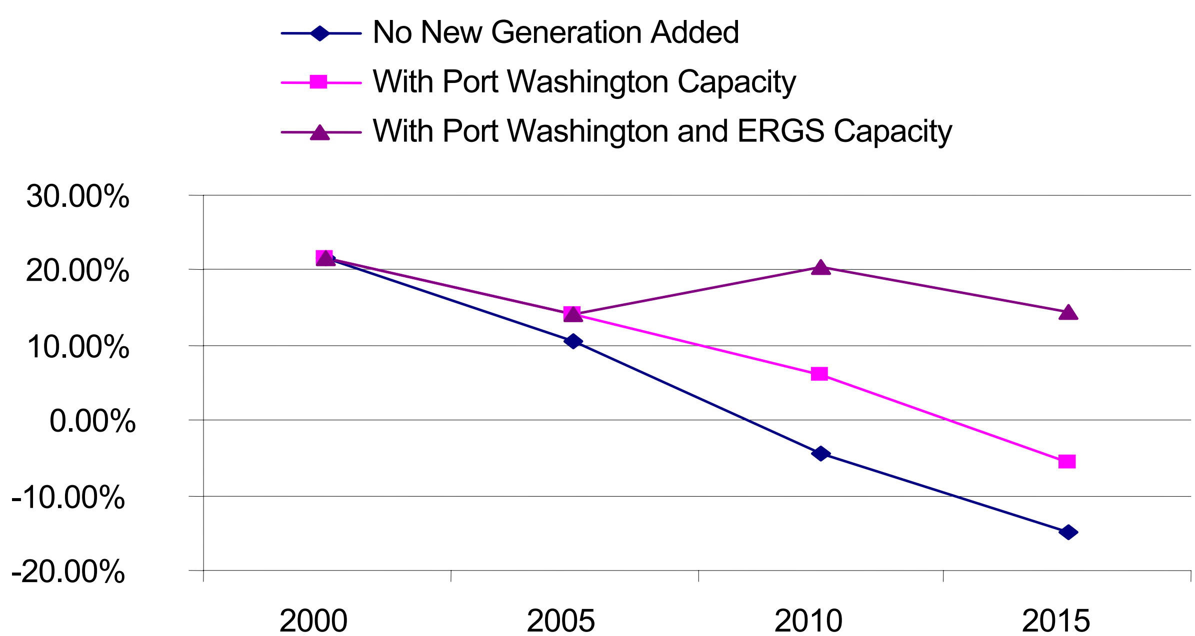


Figure 3-14 displays the WEPCO peak load demand forecast compared to the electric supply resources available to the utility if there is no expansion in existing generating capacity, if the 1,090 MW of Port Washington capacity is added to WEPCO's existing system, and if both the Port Washington and 1,800 MW of ERGS capacity is added to the existing system using the implementation schedule as set forth by the utility. Figure 3-14 demonstrates that without some type of significant capacity addition or IPP capacity after 2007, WEPCO would not be able to meet its expected peak load obligation. Data in Figure 3-14 assume that WEPCO continues to purchase as part of its existing capacity about 1,200 MWs from merchant power plants and other suppliers during the 2005 to 2015 time frame.

An alternative way to depict the information in Figure 3-14 is to examine the expected planning reserve margin for WEPCO if the capacity represented by the Port Washington and ERGS units is added to the existing system. Figure 3-15 portrays expected planning reserve margins with or without the Port Washington and ERGS units. Presently, the PSC requires the state's utilities to maintain an 18 percent planning reserve margin. (See Order Point 9, page 22, Advance Plan 8 Final Order, November 20, 1997). Figure 3-15 highlights the fact that without substantial capacity additions, WEPCO would not be able to maintain an adequate level of reliability, as the planning reserve margin quickly drops below 10 percent. Data in Figure 3-15 assume that WEPCO continues to purchase as part of its existing capacity about 1,200 MWs from merchant power plants and other suppliers during the 2005 to 2015 time frame.

Figure 3-15 Expected WEPCO planning reserve margins 2005 to 2015



Effects on the Wholesale Market

Present state of the WUMS wholesale market

Under Wis. Stat. § 196.491(3)(d)7, the Commission may issue a CPCN for a proposed facility only if it "will not have a material adverse impact on competition in the relevant wholesale electric service market." Such a determination requires an analysis of market power, which is the ability of a firm to charge prices for its product above what a competitive market would allow.

Presently, the relevant wholesale electric service market, from an anti-trust perspective, is the geographic region of WUMS (the Wisconsin and Upper Michigan system). This region is considered to be an electric "island" in which a large electric generating firm could obtain leverage over the prices paid for electricity because of transmission constraints and congestion.

This fact was documented for the Commission in an independent market power study conducted in 2000 for the Commission by Tabors, Caramanis and Associates of Cambridge, Massachusetts.[37] The WUMS wholesale electricity market is highly concentrated.[38] When a market becomes so limited, utilities or other players with a large market share or concentration can obtain leverage over the prices being paid in that market. In essence, a large electric generating firm in a narrow competitive energy market can influence prices to its advantage and everyone else's detriment. In economics, such leverage is referred to as horizontal market power and is policed by federal and state anti-trust law.

Potential effects of Elm Road Generating Station on the WUMS wholesale market

Since WEPCO turned over operational control of its transmission system to ATC in the year 2000, this analysis focuses only on horizontal market power issues associated with the construction and operation of the Elm Road coal facilities. Vertical market power issues associated with the combined operation of proposed coal plant facilities and the transmission system do not need review, given the existence of the Midwest Independent System Operator and its control over the ATC transmission system.

This same issue was reviewed by the Commission in the 2002 Port Washington CPCN docket. In that proceeding, the Commission determined that it was unlikely that there would be any adverse impacts on competition. This is because 1,090 MW of capacity and energy from the Port Washington generating units would be provided to WEPCO via a Facility Lease, at rates that the PSC regulates through its review of the lease's economic terms and conditions. Essentially, PSC economic regulation prevents any material adverse impact on competition in WUMS. The market power study conducted by Tabors, Caramanis and Associates of Boston confirmed that fixed price contracts such as the proposed Facility Lease can mitigate market power. In addition, the Federal Energy Regulatory Commission (FERC) only allows WEPCO to sell in WUMS at cost-based rates.

---

[37] See, Horizontal Market Power in Wisconsin Electricity Markets, A Report to the Public Service Commission of Wisconsin, November 14, 2000.
[38] Ibid.

In the Port Washington CPCN case, despite these observations, several parties suggested that approval of the Port Washington generating facilities could have a material adverse impact on competition by preventing the development of a competitive wholesale generation sector and hindering further electric industry restructuring in Wisconsin. The Commission did not agree with that position because WEPCO planned to continue contracting for power with IPPs, obtaining up to 1,000 MW of capacity from these providers. Relative to that amount the Port Washington facilities in total were also about the same size, constituting 1,090 MW of capacity. Furthermore, a stand-alone generation company such as WE Power LLC could more easily be divested by WEC than generating assets that are held within WEPCO as rate base assets, should a future legislature or Commission require splitting the generating plant assets away from utilities.

For these reasons, the Commission found that approval of the PWGS project would not prevent the development of a competitive wholesale generation sector nor hinder further electric industry restructuring in Wisconsin. In the present proceeding the Commission will have to examine this market power issue again. Since the regulated price feature of the facility leases has not changed, a similar result could occur. However, given the magnitude of the ERGS at around 1,800 MW, the continued fruition of a long-term competitive power market in Wisconsin, especially WUMS, could be dependent on the Commission requiring WEPCO to continue purchasing 1,000 MW or more of capacity from IPPs, as long as such purchases were cost effective and not an entitlement Additionally, the Commission could postpone the decision on the 600 MW IGCC unit and require WEPCO to solicit competitive bids from IPPs for that capacity at the appropriate time.

Chapter Summary

1) WEPCO has increased its reliance on power purchases and merchant power plant capacity. This trend has limits, translating into the potential need for new baseload and intermediate generating capacity in Wisconsin. Merchant plants have been a promising development, but many independent power producers have been experiencing financial difficulties.

2) Current WEPCO baseload units are being used extensively; the same is true for similar plants in Wisconsin. Baseload unit maintenance scheduling is increasingly more complex, requiring high cost natural gas-fired peaking plants to be used more often even during the winter months and maintenance outage seasons. Such increased usage of peaking plants raises their capacity factors, a sign of increased need for new baseload and intermediate generating capacity for WEPCO and Wisconsin.

3) Present transmission constraints do not allow WEPCO to obtain necessary capacity from Illinois where excess low cost capacity may exist, translating into a potential need for new capacity located in Wisconsin.

4) Prior Advance Plans which established optimal generation expansion plans suggested the need for new baseload power plants in the period after 2006.

5) WEPCO's demand and energy forecast for the next ten years is not unreasonable. Based on prior experience, it may be on the high side however. For this reason, using a lower growth rate demand and energy forecast as provided by the U.S. Department of Energy's Energy Information Administration (EIA) provides a useful sensitivity. Such a sensitivity reduces peak demand by about 500 MW or by about one baseload power plant during the important 2005-2015 time period.